NON-PUBLIC?: N
ACCESSION #: 9001020123
LICENSEE EVENT REPORT (LER)

FACILITY NAME: Brunswick Steam Electric Plant Unit 2 PAGE: 1 OF 17

DOCKET NUMBER: 05000324

TITLE: Manual Reactor Scram In Accordance With I&E Bulletin 88-07 Due To Loss of Both Reactor Recirculation Pumps Following a Unit 2 Loss of Off-Site Power
EVENT DATE: 06/17/89 LER #: 89-009-01 REPORT DATE: 12/15/89

OTHER FACILITIES INVOLVED: Brunswick Unit 1 DOCKET NO: 05000325

OPERATING MODE: 1 POWER LEVEL: 076

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR SECTION:
50.73(a)(2)(iv)

LICENSEE CONTACT FOR THIS LER:
NAME: R. M. Poulk Jr., Supervisor -
Regulatory Compliance TELEPHONE: 919 457-2314

COMPONENT FAILURE DESCRIPTION:
CAUSE: X SYSTEM: EL COMPONENT: XFMR MANUFACTURER: G080
X BB ISV P304
X BO ISV R344
REPORTABLE NPRDS: Y
Y
Y

SUPPLEMENTAL REPORT EXPECTED: NO

ABSTRACT:

At 2047 hours on June 17, 1989, a manual reactor scram was initiated on Unit 2, in accordance with I&E Bulletin 88-07, due to a loss of both reactor recirculation pumps. Both pumps were deenergized when troubleshooting on Unit 2 startup auxiliary transformer (SAT), which supplies power to the pumps, caused the SAT to trip on a high resistance ground fault. A planned power decrease was in progress prior to the loss of the SAT and the power level at the time of the scram was 76%.

As a result of the reactor scram and the loss of the SAT, Unit 2 experienced a loss of off-site power. The diesel generators automatically started and powered the Unit 2 emergency (E) buses per design. Due to the momentary loss of power on the E-buses and/or vessel low level (as applicable), containment isolation Groups 1, 2, 3, and 6 automatically isolated. Reactor pressure was controlled by the safety relief valves, high pressure coolant injection system, and the reactor core isolation cooling system.

The investigation determined that the cause was personnel error by the technician performing troubleshooting on the SAT. The technician placed a jumper across the SAT neutral grounding transformer primary thinking it was a current transformer; however, it is a potential transformer and the resulting high current caused the SAT to trip. Corrective actions include personnel counseling and procedure enhancements.

END OF ABSTRACT

EVENT

A manual scram was initiated on Unit 2, as required by I&E Bulletin (IEB) 88-07, due to loss of both recirculation pumps. As a result of this event, a loss of off-site power to Unit 2 was experienced.

INITIAL CONDITIONS

The Unit 2 Residual Heat Removal (RHR)/Low Pressure Coolant (LPCI) System (E11) loops A and B (EIIS/BO), Reactor Core Spray (CS) System subsystem loops A and (EIIS/BM), Automatic Depressurization System (ADS) (EIIS/*), High Pressure Coolant Injection System (EIIS/BJ), and the Reactor Core Isolation Cooling System (EIIS/BN) were in standby readiness. In addition, the Units' 1 and 2 Emergency Diesel Generators (DGs) Nos. 1-4 (EIIS/EK/DG) were in standby readiness. In accordance with Engineering Evaluation Report (EER) 89-0163, the RHR Service Water (RHRSW) System (EIIS/BI) was aligned with RHRSW pump 2A (EIIS/BI/P) in service to ensure the capacity requirements of the unit Nuclear Service Water (NSW) header (EIIS/BI/PSX). Unit 1 was in a planned Maintenance outage.

At approximately 1800 hours on June 17, 1989, a Startup Auxiliary Transformer (SAT) (EIIS/EL/XFMR) winding ground current alarm was received in the Unit 2 Control Room. It was also noted that some of the grounding resistors (EIIS/EL/**), located on the secondary side of the grounding transformer, (EIIS/EL/XFMR), were extremely hot. During normal plant operation, the SAT supplies power to the balance of plant (BOP) electrical bus 2B (EIIS/EA/BU), which provides power to the reactor recirculation pumps (EIIS/AD/P), and the Common B bus (EIIS/EA/BU). The remaining BOP electrical buses (2C and 2D) (EIIS/AD/P) are powered from the Unit Auxiliary Transformer (UAT) (EIIS/EA/BU), which is powered by the unit's generator (EIIS/EL/GEN). As the SAT is maintained and repaired by the Wilmington Area Transmission Maintenance Unit (TM), the main power grid load dispatcher was notified of the alarm and the need for assistance. TM personnel from the Wilmington District reported to the site and began to investigate the subject ground current alarm.

During this same time period, discussions were held between Control Room personnel and the plant General Manager on the plant effects of losing the SAT, and the subsequent requirement to scram the reactor, per IEB 88-07, if the recirculation pumps were deenergized. Due to the possibility of losing the SAT, it was decided to decrease reactor power to less than the 50% load line to ensure the reactor would not be operating in the region of instability should the SAT be lost. Power had been decreased from 100% to 76% by decreasing recirculation flow. The plant had not yet reached the point in the

*EIIS system description unavailable
** EIIS component-description unavailable

power decrease to begin inserting the control rods; therefore, the unit was still operating with a 100% rod pattern (100% load line).

EVENT DESCRIPTION

After arrival at the site, TM personnel initiated troubleshooting activities by taking current readings on the SAT neutral grounding transformer. Based on these readings, it was determined that a ground did exist. In a effort to determine where the ground was located, plant maintenance and technical support personnel monitored the loads on the 2B bus and the 4160 volt bus feeder ground fault instrumentation, while the TM personnel checked out the SAT. Current readings, temperatures, and transformer checks indicated that the SAT and the loads on the 2B bus were normal.

In an effort to clear the alarm and to show that the ground condition was located on the plant's 4160 volt bus, the TM technician decided to short around the grounding transformer. At shortly before 2047 hours when the technician placed a grounding cable across the ground transformer primary, he created a low resistance ground path for the already present ground. The resulting high current flow vaporized a portion of the grounding jumper and burned off the tip of the hot stick he was using.

At the same time, compartment covers (EIIS/EL/DR) on two sections of the nonsegregated phase bus duct enclosure (EIIS/EL/BDUC) blew open and an insulator bushing (EIIS/EL/INS) was destroyed in the nonsegregated phase bus duct. At 2047 hours, the SAT tripped due to the fault.

The loss of the SAT caused the 2B bus to deenergize, thereby causing the reactor recirculation pumps to trip. In accordance with IEB 88-07 and plant Abnormal Operating Procedure (AOP) 4.3, Dual Recirculation Pum

Trip, a manual scram was initiated to ensure the reactor was not operated in the region of potential instability. Following the reactor scram and subsequent turbine trip, power to the unit from the UAT was lost, resulting in a loss of off-site power to Unit 2. Unit 1 was not affected by this event except for receiving a Group 6 isolation on the loss of power to the stack radiation monitor which was powered from Unit 2.

Following the reactor scram, containment isolation groups 1, 2, 3, and 6 occurred due to low level (shrink) and/or the momentary loss of power to the emergency (E) buses. The diesel generators (D/G) for both units auto-started on the undervoltage signals from the SAT and the Unit 2 D/G's reenergized their E-buses following the loss of power from the UAT. Reactor pressure and level were controlled by the ADS safety relief valves (SRV) (EIIS/*/RV), HPCI, and RCIC. Operation of the HPCI and RCIC systems was in the manual mode as plant conditions did not require automatic operation. SRVs A, B, C, D, F, and G automatically opened during the initial stages of the event, and SRVs A, B, E, F, and G were subsequently manually opened until HPCI and RCIC were placed

*EIIS system description unavailable
**EIIS component description unavailable .

into service for level and pressure control. The minimum recorded reactor level during this event was 150 inches and highest recorded pressure in the reactor steam dome was 1150 psig as indicated by pressure indicator (PI)-R004A (EIIS/AC/PI), 1090 psig as indicated by PI-R004B (EIIS/AC/PI), and 1120 psig as indicated by reactor condensate/feedwater (C32) procedure transmitter (PT) - C32-PT-N005A/B (EIIS/JA/PT). Suppression pool (EIIS/*/**) temperature reached 122 degrees during the event due to SRV and HPCI/RCIC discharge into the pool. A sequence of events is provided in TABLE 1. At approximately 0330 hours on June 18 power was restored to the BOP buses by backfeeding through the UAT from the switchyard and off-site power was restored to the emergency buses from the BOP buses at 0622 hours.

During the scram recovery and subsequent system operations prior to returning the unit to power, two additional problems were identified. First, was the failure of the Unit 1 CAC-V10 valve (EIIS/BB/ISV) to close on the Group 6 isolation signal and on subsequent remote manual attempts with the control switch from the Control Room. The redundant valve, CAC-V9 (EIIS/BB/ISV) did close to provide isolation for that containment penetration. CAC-V10 is an 18-inch drywell purge and vent valve.

The second problem was identified on June 19 while attempting to place Unit 2 into shutdown cooling on the A-loop of the RHR System. While attempting this operation, it was determined that no flow or temperature increase was realized. Troubleshooting the problem determined that although the Control Room indication and valve stem indication showed the RHR low pressure coolant injection valve open, the valve, 2-E11-F017A (EIIS/BO/ISV), was in fact closed.

Following repairs to the affected equipment associated with the SAT, the CAC-V10, 2-E11-F017A, Unit 2 was returned to critical operation at 0050 hours on June 28 and was tied to the grid at 1640 hours on June 28.

EVENT INVESTIGATION

Investigations into these events were conducted by the Site Incident Investigation Team, plant personnel, a special investigation team made up of senior company TM personnel, and an independent team made up of Corporate and On-site Nuclear Safety personnel and INPO personnel. The root causes are as noted for each event.

Loss of SAT

As previously noted, when the technician installed the jumper, several events occurred immediately. The investigation into the initiating event (the event causing the ground alarm at 1800 hours) determined that the bus duct contained water which contributed to the current path to ground. The jumpering evolution completed the phase-to-ground-to-phase current path by shorting the high resistance. It is not known if the water came from condensation or from heavy rains which fell during that day, or a combination of both. An inspection of the ducting could not identify an intrusion path for moisture which is

believed to have existed prior to the event. In addition, it was found that the bus duct heaters (for condensation) were operable. No routine preventive maintenance could be identified on the bus duct or the drains which are located on some of the bus duct sections.

TM maintenance personnel who responded to this event were not familiar with the SAT neutral grounding system. Within the Wilmington TM area, current transformers are routinely used to provide grounding detection at the various substations with shorting across the windings of a current transformer as an accepted method of troubleshooting. The ground detection method used on the transformers at Brunswick (SAT, UAT, and the Caswell Beach Pumping Station Feeder Transformer) utilizes a distribution (potential) transformer instead of a current transformer. While troubleshooting, potential transformers should not be shorted. The technician knew the difference between the troubleshooting criteria for the two different transformers; however, he failed to recognize that he was working with a potential transformer.

A review of the training history of the involved technician revealed it was based upon on-the-job training. Due to his level of expertise at the time the company Craft and Technical Development Training program was initiated, he was "grandfathered" with respect to his job function. A review of the Craft and Technical Development Training program on high resistance grounded systems indicates that a minimum of information is provided that would have helped the technician, had he taken the course.

Communications between the technician and the Control Room were inadequate in reference to installing the jumper across the potential transformer. The technician requested permission to "jumper" the signal to the alarm circuit to verify that the alarm would clear. He stated this evolution presented no liability to plant operation. (NOTE: If he had been troubleshooting a current transformer, this would be true.) The Control Room personnel thought that he was going to install a jumper across alarm relay contacts (EIIS/EL/CNTR), and did not realize that he was jumpering the grounding transformer. Control Room personnel state that had they understood what the technician intended to do, they would not have given permission to install the jumper until Reactor power had been further reduced.

The investigation also determined that the plant operating procedures were inadequate in that they did not allow for operation of the BOP 4160 volt 2B bus (power to the recirculation pumps) on the UAT. Initial design and operation of the 2B bus had it powered from the UAT. On a loss of the UAT (turbine trip, etc.), the BOP 4160 volt buses 2C and 2D would transfer to the SAT; however, it would be a dead bus transfer (i.e., a momentary loss of power). The 2B bus would remain on the UAT until manually transferred to the SAT. Due to multiple scrams on Unit 2 during the early years of operation and the subsequent loss of recirculation pumps, it was decided to maintain the 2B bus on the SAT during operation, as the pump seals (EIIS/AD/SEAL) were experiencing degradation as a result of the trips. Subsequently, improved

seals were installed in the recirculation pumps; however, operation to the 2B bus was not restored to the UAT due to core thermal limit analysis which now took credit for the pumps (bus 2B) being powered from the SAT. Procedures were revised to delete operation of bus 2B on the UAT instead of possibly providing core thermal limit reductions if the 2B bus had to be aligned to the UAT. An event and cause chart is provided at the end of this report.

CAC-V10 Failure to Close

The investigation into the failure of the CAC-V10 to close determined that the solenoid valve which ports air to this valve appeared to be hung up in a fixed position. The system engineer was notified and assisted in the troubleshooting. The solenoid valve was replaced, restoring the CAC-V10 to operational status, and the failed valve was disassembled. The results of the initial inspection of the solenoid valve were inconclusive. The valve was sent to the company laboratory for further analysis.

The failed valve was visually examined and disassembled with the assistance of Brunswick Maintenance personnel. It should be noted that the failed valve was not bench tested to determine if it would function properly prior to disassembly. An electrical continuity check of the solenoid showed the solenoid was satisfactory.

During disassembly, five observations were made. First, the smaller end cap opposite the "U-cup" and the mating end of the plunger assembly were observed to have a significant amount of deposits/particulate present on their surfaces. Second, the "U-cup" components were observed to be coated with a black, oily substance which was considered to be unusual because these valves supposedly used silicone lubricants which are almost transparent. Third, the motion of the plunger assembly in the "plunger sleeve" was found to be more restrictive in one direction than the other. Fourth, some evidence of mechanical abrasion was present on the "bearing" end of the plunger assembly which moves within a mating hole in the smaller end cap. The elastomers associated with the "switching" assembly controlled by the solenoid were observed to be in relatively good condition. No other unusual valve conditions were observed. At this point, it was thought that the observed black, oily substance and the motion restriction may be related to a potential degradation of the EPDM elastomers used for the external and internal "U-cup" seals. It was further thought that the observed condition may be indicative of the introduction of hydrocarbons which could potentially cause swelling and dissolution of these elastomers (EPDM) and thus restrict movement of the valve.

The failed valve was taken to Rexham Analytical Services in Matthews, North Carolina for further analysis. The primary purposes of this analysis were (1) to identify the elastomer components and the black, oily substance present on certain valve components and (2) to analyze the elastomer components for evidence of degradation. In the report generated by Rexham Analytical

Services, the black oily residue was identified as being a silicone lubricant and the elastomers were identified as consisting of EPDM. No significant evidence of hydrocarbons was detected in either the EPDM elastomers or the silicone lubricant. The results of these analyses revealed no abnormal observations associated with the examined valve components which would account for the reported valve failure.

An analysis of a sample of the observed debris/particulate present within the failed valve was performed using a scanning electron microscope (SEM) with an attached energy dispersive X-ray spectrometer (EDS). The results of this SEM/EDS elemental analysis revealed the particulate to consist of silicon and iron. Based on the visual appearance of this particulate (i.e., a rusty-tan color), it is thought that the particulate is most likely rust (iron oxide), dust and dirt (silica). This type of deposit is consistent with deposits associated with other Brunswick plant solenoid valves which have been analyzed in the past. Several larger metallic flakes were present in these particulate de
osits. SEM/EDS
elemental analysis of these metallic flakes revealed a composition consistent with Type 316 stainless steel. The solenoid valve consists of copper-based alloys with the exception of the solenoid housing, the disk assembly, and core assembly. The solenoid housing consists of a nickel plated plain carbon steel. The core assembly consists of a ferritic or martensitic stainless steel. The disk assembly consists of austenitic stainless steel components. Therefore, it is possible that the observed metallic flakes are from either the disk assembly or an external source.

Further examination of the abrasion marks present on the "bearing" end of the plunger revealed these marks to be (1) rather shallow, (2) oriented in the longitudinal direction (axial) (3) and present on about one quarter of the outer circumference to an approximate maximum depth of one quarter inch. Examination of the smaller end cap's inner diameter (which contacts the "bearing" end of the plunger) revealed the presence of (1) circumferential machining marks, (2) one fresh circumferential "scratch", and (3) a general "burnishing" of approximately one quarter of the inner circumference for a nearly constant depth of approximately one quarter inch. It was also noted that the observed burnishing was apparently due to abrasion occurring in the longitudinal direction (axial) of the solenoid valve (which would correspond to the abrasion observed on the plunger assembly) and that the "fresh" circumferential scratch was present within the burnished area. The outer diameter of the plunger was 0.495-inch and the inner diameter of the smaller end cap was 0.500-inch.

2-E11-F017A Failure to Open

The investigation into the failure of the F017A to open determined that the valve stem and disc had become separated, leaving the disc in the seat when the stem traveled to the open position. The valve had been rebuilt in 1986, at which time the disc and disc nut were separated by removing the locking pin to accommodate installation of a new valve stem. Upon reassembly, the disc was screwed onto the disc nut and a new locking pin was installed into the hole in the disc. However, the new locking pin was not inserted far enough into the hole so that it engaged the disc nut. Vibration and flow through the valve caused the disc to eventually unscrew from the disc nut.

At the location of the locking pin hole, the disc is approximately 13/16 inch thick, while the locking pin is 3/4 inch long. It is believed that the pin had been installed flush with the disc surface; therefore, not providing the required engagement. A review of the maintenance of the F017B and the two F017 valves on Unit 1 has determined that these valves are correct. The mechanics who performed the maintenance on these other valves recall that the pin was recessed approximately 1/4 inch when the lock welds were installed. This would allow for approximately 3/16 inch engagement which is considered adequate.

This event is felt to have occurred due to a procedural inadequacy. The procedure used to perform this maintenance, OCM-VGB510, Rockwell Pressure Seal Angle Globe Valves, did not provide a method to verify proper disc-to-disc nut locking pin engagement.

CORRECTIVE ACTIONS

Loss of SAT

The physical damage which occurred when the jumper was installed has been repaired and the Unit 2 SAT has been restored to service. In addition, the remaining "Y" bus ducts for both units were inspected for water, with no additional problems identified. After both units were restored to operation with the SATs carrying their normal loads, the "X" and "Y" neutral ground currents were measured with no noticeable current indicated. This was done to verify that no additional grounding problems existed.

Additional corrective actions are as follows:

1. Item specific instruction has been given the Wilmington Area Transmission Maintenance Relay and Substation Maintenance Crews.

2. The Wilmington Relay Crew and Leland Substation Maintenance Crews have been assigned the task of preparing a training document for major equipment at Brunswick that could impact off-site power reliability. Included in this assignment is identification of purpose and maintenance tasks associated with the Generator, Unit Auxiliary Transformer, Startup Auxiliary Transformer, Motor Operated Air Break Switch, Main Bank

Transformers, and Unit Power Circuit Breakers. Class-room type training sessions will be held during which the documents(s) will be presented and discussed. Wilmington Area Transmission Maintenance Engineering staff and management will monitor the training sessions.

3. Procedures for the 1989 Unit 2 Outage for Relay Maintenance have been updated and have had peer and management review.

4. Review is underway to determine if the wording -- Caution - High Voltage Possible is the most appropriate for this application or if some other wording would be more desirable. Transmission Maintenance personnel will stencil the resultant caution indicator on the equipment at Brunswick.

5. The Minutes of Special Investigation of this incident have been distributed to each Transmission Maintenance Area.

6. Technical Support-Electrical Systems is currently conducting a design review of the bus duct system to develop a preventive maintenance program. This includes conversations with the current vendor representative (Delta-Unibus). Another aspect of our plan includes the visual inspection of the outdoor portion of the bus ducts associated with the SAT and UAT transformers. This is comprised of 2 ducts per transformer or a total of four per unit.

Inspection of the Unit 2 bus ducts will occur during the current Unit 2 outage. Unit 1 bus ducts will be inspected during the next scheduled refueling outage (scheduled to commence in June 1990).

Once the inspection data is obtained and evaluated, appropriate preventive maintenance criteria will be developed. The current bus duct components that we anticipate to be included in a preventative maintenance program are the filter drains located in the removable, bottom covers; space heater operation and supporting insulator condition.

These corrective actions will be completed by February 1991.

CAC-V10 Failure to Close

As noted previously, the failed solenoid was sent to the company's laboratory for failure analysis. The exact cause of failure for the 1-CAC-SV-V10 solenoid valve could not be determined. With the exception of the "U-cup" elastomers, most of the valve elastomers were found to be in excellent condition based on visual inspection. The "U-cup" elastomers were observed to be coated with a black, oily substance thought to be indicative of degradation of these components. Analyses performed by Rexham Analytic Services showed this black, oily residue to be a silicone lubricant mixed with a graphite coating which is

used by ASCO. Based on these results, the observed abrasion of the plunger assembly and the end cap was thought to be the most likely cause for failure. Although no binding was noted during disassembly, it may be possible that the introduction of foreign particulate could cause binding of the plunger within the valve. Although the clearance between these components is five mils (0.005-inch), it is possible that the plunger could become misaligned and the combination of this misalignment and foreign particulate could produce binding or restrict the movement of the valve. In summary;

1. The cause of failure of the 1-CAC-SV-V10 solenoid valve could not be determined.

2. No evidence of degradation of the elastomers used in the 1-CAC-SV-V10 solenoid valve was found.

3. Substantial amounts of particulate thought to be a combination gf dust, dirt, rust, and metallic flakes were present inside the smaller end cap side of the 1-CAC-SV-V10 solenoid valve.

4 Evidence of mechanical abrasion of the "bearing" surfaces (i.e., the inner diameter of the smaller end cap and the outer diameter surface of the plunger assembly) associated with the smaller end cap side of the 1-CAC-SV-V10 solenoid valve was observed.

F017A Failure to Open

The F017A was disassembled, repaired, and restored to operation. As previously noted, the operability of the remaining F017 valves were verified. The procedure for maintenance of these valves has been revised to incorporate proper guidance on the disc-to-disc nut engagement. Additional corrective actions were identified in many areas by the independent investigation team comprised of corporate and On-Site Nuclear Safety personnel. These items will be tracked on the Facility Automatic Commitment Tracking System to assure resolution.

EVENT ASSESSMENT

The loss of auxiliary power to the unit (all off-site grid connections) is an analyzed accident in the facility Safety Analysis Report (Section 15.2.5). This event is less severe in that reactor power had been decreased to approximately 76% prior to the loss of power. In addition, the scram was manually initiated prior to losing auxiliary power, thereby increasing the margin to the core thermal limits.

The separation of the stem and disc on the 2-E11-F017A would not have prevented the A-loop (A and C pumps) of LPCI from injecting on a LOCA signal. The F017 valve is a normally open angle-type globe valve. Although the valve disk was still in the seat when the valve was thought to be open, the valve due to its configuration, should have acted like a lift check valve when RHR flow was initiated. The vendor was contacted and was in agreement with this conclusion. Based on calculations, the LPCI system would need to provide an additional 1.71 psi to lift the disc from the seat. Surveillance requirements for the LPCI system require the A-loop provide 17,000 gallons per minute at a discharge pressure of 149 psi. Periodic testing conducted on May 10, 1989, indicated that the A-loop discharge pressures were 164 psi on the A pump and 165 psi on the C pump.

TABLE 1

LOSS OF OFF-SITE POWER

SEQUENCE OF EVENTS

June 17, 1989

18:00 Annunciation of a ground on the Station Auxiliary Transformer (SAT) was received. An operator was dispatched and reported a current transformer to be overheating (the grounding resistors were hot). The Wilmington Relay Crew was contacted.

18:30 Panel XU-8 shows flag for "SAT GRD current Y winding". Informed SRO who reset flag.

18:45 Telecon with Shift Operating Supervisor (SOS), Acting Operations Manager, and Plant General manager (PGM). Direction given to reduce power to 50%.

19:00 Operations turnover. Substation Maintenance arrives.

20:00 Wilmington relay crew arrived.

20:10 Power reduction began.

20:38 2A RFP (reactor feedpump) went into oscillations. Trouble controlling reactor level. Relay crew contacted Control Room to indicate use of jumper to check annunciator. Permission given to reset alarm with jumper.

20:47 PGM called SOS office to learn status of plant.

Troubleshooting was in progress on the "SAT" grounding circuit. (See 20:38 entry). A jumper was connected across the primary of the grounding transformer on the "SAT". Connection of this jumper created the second half of a major short in the 4160 volt (secondary) side of the "SAT".

20:47:19 230 kV bus 2A primary lock out is generated. With bus "2A" tripped, the Unit 2 SAT" and the "Caswell Beach" feeder are deenergized. Recirc pumps trip.

TABLE 1 (Cont'd)

20:47:20 All four DGs receive a start command on the "SAT" undervoltage.

The four DGs attain rated speed. DG 1 and 2 are not required and run unloaded. DG 3 and 4 do not load as the "E3" and "E4" are still powered from "UAT".

20:47:55 Per AOP-04.3 (Dual Pump Trip), a manual scram is inserted by the reactor operator.

20:48:02 Decrease in reactor power causes a decrease in reactor level (shrink), low level alarm received.

20:48:03 Level continues to shrink, all four low level one (> or equal 162.5") scram signals are received, both channels of RPS generate auto scrams. Group 2 and group 6 isolation commands are generated. Note - the group 8 isolation command was already present due to normal operating pressure in the steam dome.

20:48:10 Loss of voltage on the "E" buses causes a loss of power to the main steam line leak detection logic causing all four channels to trip. A group 1 isolation command is generated.

20:48:10 Turbine trip signal received: UAT is lost.

20:48:10 Bus "E3" and "E4" indicate an undervoltage condition.

20:48:14 Bud "E3" undervoltage clears when DG 3 ties in. Group 3A isolation signal is generated when the "SCAM" temper